Mr. Mihaly.

MR. MIHALY: Q Have you had any contacts with Ramco over -- concerning these peakers -- you personally?

A Personal contact --

Q Yes.

A -- with Ramco? Let me think a moment. My contact with Ramco on these units has been in the area of the interconnection study work for these units.

Q Could you describe what that involved?

A Just as any other applicant who desires to construct a generating unit and interconnect with the SDG&E system is required to do, Ramco filed application to connect, I believe, a total of three of these peaker units with the SDG&E system.

And upon our acceptance of those applications, those units were placed in our generation interconnection queue.

We then tendered them a contract ~~review~~ for interconnection study, which Ramco executed for each of these units. I believe they were one study for the first two units, and a separate study for the third unit, for the Chula Vista 2 unit that you asked me about earlier that was the subject of a letter to Commissioner Laurie. And we conducted those interconnection studies, and published those study results, and provided copies to Ramco and to the California ISO.

Q About when was that?

A That would have been last year.

through the Mexican system in Baja California to the west, and then some part returning north from Tijuana to Miguel. Is that what you were asking me about?

MR. MIHALY: Q That is correct. I realize that Path 45, that does not describe that entire system. For ease of --

ALJ COOKE: Wait. Can I just ask a clarification question?

MR. MIHALY: Please.

ALJ COOKE: Mr. Korinek, are you saying that from your -- that Path 45 does not include the Mexican system; it includes simply the lines from SDG&E's system that go to the Mexican substations?

THE WITNESS: That's right, your Honor.

ALJ COOKE: Okay. Thank you.

MR. MIHALY: Q So my question is: Do you know the amount of the unscheduled flow that would follow the route you just described?

A Well, that depends entirely on the operating conditions at the time of the event.

Q In what way does it depend on the operating conditions?

A It depends on the flow levels from as ~~as~~ Arizona to southern California. It depends on any generation that is or is not operating to the east of Imperial Valley in either the Imperial Valley or Mexicali area. So it depends on a host of variables, as well as the SDG&E import level at the time, and the CFE Baja California import level at the time. So there is no single answer.

Q Is there a range?

A Yes.

Q What is it?

A A typical range for that number could be from zero to hundreds of megawatts.

Q Hundreds?

A Mm-hm.

Q As in 100, 200, 300, or 1,100?

A I would not expect to see an unscheduled flow anywhere near 1,100 megawatts. And any unscheduled flow of that level would immediately cause an ~~eruption~~ interruption of the path ~~using~~ -- based on the operation of existing protective devices through that unscheduled flow path, so that the flow level you mentioned would only be there for a moment, and then it would be zero.

ALJ COOKE: Mr. Korinek, on this diagram --

THE WITNESS: Yes.

ALJ COOKE: -- there are quite a few proposed 230-kV transmission lines shown on it. Would those transmission lines be -- as they head to the Mexican substations from the SDG&E system, would they be considered part of Path 45?

THE WITNESS: There are two lines that are drawn on this diagram that are dashed as future proposals that would become part of Path 45. That would be the dashed green line between La Rosita and Imperial Valley, and the dashed line between Tijuana to the proposed Otay switchyard to Miguel. Those would become part of Path 45.

you'd like to turn there.

Q Sure. This is Exhibit 207. And I believe we're talking about some discussion that occurs on page 9 of Exhibit 207 in the, I guess, first numbered paragraph.

A Actually, it's San Diego Gas & Electric's Exhibit 6, Reference Appendix E, which was filed on April 12th of 2002.

ALJ COOKE: Let's be off the record.

(Off the record)

ALJ COOKE: Let's be back on the record.

While we were off the record, we verified that this exhibit has been marked twice: as Exhibit 6, and as Exhibit 207. It is the SDG&E and California review group's accepted rating report of the south of SONGS Path 3 Re-rating. Let's just, for ease of reference, use Exhibit 6.

And what was your question, Mr. Scarff?

MR. SCARFF: We were talking about the Edison Del Amo-Ellis line, and its role in the Path 44 rating. And that, I believe, is discussed on page 9 of Exhibit 6. ]

And let me -- after Mr. Korinek has had a chance to look at that.

My understanding is that the study group wanted to keep the South-of-SONGS rating at 2500 megawatts out of concern of what would happen to the system after the loss of SWPL, after the loss of Encina, if the Del Amo-Ellis line were to have an unscheduled outage; is that your understanding of the discussion here?

A Well, page 9 that you have referred to, at paragraph 3, No. 1, specifically states that under 2500 megawatts South-of-SONGS flow and SWPL open conditions, the loss of the SCE Del Amo-Ellis line loads ~~to~~ the Barre-Ellis 230 kV line to 99.8 percent of its N minus 1 contingency, quote, A, unquote, rating of 2,850 amps, period.

I believe that answers the question.

I might point out that while you were looking for the cite, I checked Edison's system map. And it appears that the Del Amo terminal is actually in Los Angeles County, and the Ellis terminal is in Orange County if I understand their map correctly.

Q So if we read this report here, the paragraph you just quoted from, it says that that loading is acceptable under the circumstances, but that that -- would it be fair to say that the -- let me restart.

You've had two contingencies already. You've had -- well, let me -- when we talk about Encina 5 as being the first event, G-1 event, we're talking about an unscheduled outage at Encina?

A No, that can be either a scheduled or unscheduled. There's nothing in the criteria that says that that has to be a forced or unplanned outage. In my interpretation it could be a planned outage as well.

Q The SWPL outage we're referring to is likely -- well, can that be -- is that just a forced outage?

A That would refer to a forced outage, yes.

Q So you've gotten Encina down. You've got this forced outage at SWPL, and now your concern is to protect

Project in 2005.

The ORA's testimony did not suggest combinations of its alternatives, that I recall, involving partly ~~blocked~~ block transfers and partly other upgrades.

So we assumed that, by and large, it was your intent that such alternatives would have a stand-alone benefit. And we assumed in this case that if we were going to use this blocked transfer concept -- and it may be worth my explaining it further in terms of what it's intended to do -- but if that was the approach that one intended to take, that that would be the course that you would stay until Valley-Rainbow were needed. That was the basis for my analysis.

Q Have you or your staff discussed this alternative with Edison?

A Not to my knowledge, no.

Q If you were to do some block transfer, would the first 50 or 100 or 200 megawatts of this transfer be the least costly to implement of all the potential block transfer to Orange County -- in Orange County?

A No; it could actually be the most expensive to implement.

Q And why would that be?

A That's simply because there are currently no interconnections of any kind between San Diego Gas & Electric's ~~130A~~ 138 kV facilities in Orange County and Southern California Edison's 69 kV facilities in Orange County.

That means that transformation substations would have to be built on new sites with new right-of-way between our ~~130A~~ 138 kV system and the Edison 69 kV system to the

north

in order to accomplish 1 megawatt of load transfer. Costs for that first megawatt could be astronomical.

MR. SCARFF: We're winding down our questions here slowly, your Honor.

Q One of the options that was put forward by ORA was the use of series reactors on the SONGS corridor to optimize the use of the existing 230 kV transmission lines.

And I believe you indicated cost of 25 to 30 million dollars. And this would be on page 2-1 of Attachment 7 -- 20 to 50 million dollars -- excuse me -- for the cost.

Has San Diego Gas & Electric studied this option?

A We have studied the use of series reactors on 230 kV systems, yes.

We have not studied the use of them on the South-of-SONGS system or North-of-SONGS system to my recollection.

Q And is there any reason why you haven't?

A We don't feel there is any benefit to doing so.

Q What is the basis for your cost estimate of 25 to 30 million dollars?

A We surveyed various databases that were available on the cost of series reactors, including databases published on web sites by the Department of Energy and also by the Pacific -- I'm sorry -- the Pennsylvania/Jersey/Maryland PJM Power Pool and other parties and found that those costs came out to this range

ALJ COOKE: So there could be a momentary or very short-term serving of the load with the additional loss of Valley-Rainbow in this hypothetical but not a longer duration?

THE WITNESS: Yes.

For example, a lot of these ratings may have a one-hour limit on them. So the operators during that one hour would take the additional actions necessary to either reduce the South-of-SONGS path loading -- path schedule, I should say, down to 2,500 megawatts; or, if they were able to restore the Southwest Power Link within that one hour, then they would be able to avert any further load shedding.

ALJ COOKE: Thank you.

MR. SCARFF: Q When you say further -- when you're talking about reducing the -- if you had to reduce the imports down to this 2500-megawatt limit, this would mean you would have to -- and the only way you can do that would be to shed load.

You'd have to shed somewhere between 700 and 900 megawatts of load depending upon what the rating of the path was, ~~at~~ 3200 or 3400 megawatts, before Valley-Rainbow went down?

A You're suggesting the case where the Southwest Power Link cannot be restored to service within the one-hour emergency rating example --

Q Yes.

A -- that I explained to Judge Cooke?

And you're saying what would then take place?

How would the ISO operator deal with that?

You've got -- I think we had said that the general -- the first action was dispatching that remaining generation which brought the import level down to 3,420 megawatts.

Then I'd said, assuming that the firm path rating declared by ISO was 3200 megawatts, that we would have to drop ~~320~~ 220 megawatts of Orange County and San Diego County. customer load.

So you're saying the hour has now -- is now about to expire; and in spite of SDG&E's and the ISO's best efforts, the Southwest Power Link is still out of service.

The ISO operator at that point would be required to take further action for he is in violation of emergency ratings. He is in violation of WSCC operating criteria, and he is at risk of sanctions.

He's also at risk of burning the system down.

At that point in time, he would have to order additional load shedding, would be my assumption, unless he had come up with some other solution that wasn't previously available; and I have no idea what that would be.

The only thing I can think of, practically speaking, would be to order further load shedding in the San Diego and possibly even in the Edison service area. I don't know what overloads he might be trying to counteract at that time.

Q You described a situation of what would happen if Valley-Rainbow went down and how that could lead to load rating.

Q And this is because the greater the assumed minimum wind speed, the greater convection of heat away from the conductor?

A Yes, that's true.

Q Okay. Is it correct that SDG&E rates on a thermal basis its transmission lines, using an assumed wind speed of 2 feet per second?

A Yes. As I recall, that's correct.

Q And would SDG&E's thermal ratings of all your lines increase if SDG&E assumed wind speeds that were higher than 2 feet per second?

A If you made an arbitrary rating assumption to go to a higher wind speed than the overhead-conductor portion, the lines would be at a higher rating. The terminal equipment and underground portions of lines would not be affected by an assumption of higher wind speed.

Q Consistent with your last answer. So if SDG&E increased the assumed wind speed to, say, 4 feet per second, the thermal ratings of the conductor parts of the line would increase?

A You're referring again to the overhead portion?

Q Correct. Overhead portion.

A The conductor portion?

Q Yes.

A Yes. If you ~~need~~ made an arbitrary assumption of that kind, yes, they would increase.

Q Would that increase be approximately, say, A The answer to that would be based on my Table 1, your Honor, from page 2-9 of my April testimony. And it's the bottom row of Table 2-9, where it shows the G-1/N-1 defficiency.

Whatever project were pursued to meet the requirement would have to be able to increase the nonsimultaneous import number by the amounts shown on the bottom row of Table 1.

So in Year 2005, that first year of that project for that plan of expansion -- because it might be multiple projects, if you use the ORA's approach: a small project followed by a bigger project followed by a large project. The first year's expansion plan would have to allow for 81 megawatts of increase in the NSIL.

And then the second year would have to increase that to 234 level, so it would be an increase of about 150 or -60 megawatts, I believe.

And then that -- you can see that amount increases roughly by 120 to 150 megawatts a year. That would be the amount of incremental import capability that would be required in a grid-expansion plan.

Q And that would be the amount of import capacity that would be required, assuming no change to the in-basin resource -- generating resources?

A That's correct, assuming no increase or decrease in the available in-basin generation resources.

Q Okay. If Valley-Rainbow is constructed, are the loss of SWPL and Encina 5 -- do they remain the key

Rainbow Substation were not constructed?
A There would be no additional substation required. I'm sorry. You said --
Q In order to perform the Talega-Escondido upgrade.
A If you wanted to perform the Talega-Escondido upgrade, you wanted to ~~adjust~~ add a second circuit to those existing towers --
Q Correct?
A -- and not loop in at Rainbow, you would not need any new substations. You would simply add substation equipment at Talega, and add substation equipment at Escondido, and string the new transmission conductors in a vacant position on the existing towers.
Q Okay. Thank you. If you could turn to the next page of Exhibit 1, where you're discussing the system voltage-support component of the project --
A What line is that, your Honor?
Q Line 8 and following, on page 2-6 of Exhibit 1.
A 2-6. Yes. I see it now.
Q We've already discussed the need or the value of this part of the project. If there was no 500 kV line constructed, would such voltage system support be necessary as a result of additional transmission expansion; for example, a Mission-Miguel expansion project?
A We haven't seen a need for reactive support for projects like that to date.
Q All right. If you could turn to page 2-7, in lines 10 through 14, you discuss the concern regarding

common mode failures?

A Yes.

Q It's been my observation that transmission lines are frequently located in close proximity to one another, just from driving in various places in this country and in other countries. Are there statistics that you relied on to support your fundamental argument that power lines in common corridors fail more frequently than those that are geographically isolated?

A Well, I'm reflecting recent operating experience, your Honor, with the San Onofre switchyard outage that caused an outage of the whole path in February of this year, as well as WSCC planning and operating practices that require WSCC member systems to look at the outage of facilities on a common corridor, and to plan accordingly.

Q And based on your experience, are you aware of whether these are based on any observations of that common corridor that transmission lines fail more frequently than those that are geographically isolated?

A Oh, by all means, yes. That type of historical data is clearly available.

Q Okay. And where would that type of information be available?

A That would be available in a variety of sources, probably in WSCC databases, also in the databases of the individual utilities. On a nationwide basis, it might even be available in some more common database, such as a Department of Energy database, but I don't know if that's continues, then, on to page 2-23. And you indicate that the -- that on attachment -- that Attachment 4 shows the various proposals and the new generation from western Arizona and Baja California, Mexico. Is that correct?

A Yes, I see that.

Q From what I can see on Attachment 4, it appears that all of the generation that's described there is in Mexico or in California.

A Yes. I see your question. And I didn't realize until you pointed it out just now that we did not actually show the location of any new generation in Arizona on this diagram, and I apologize for that.

Q Could you go through the expected Arizona generation, and the capacity of those?

A Yes. I can give you information on that. And I'm trying to think if we may have provided that in a data response; we probably have, but let me simplify it if I may.

There is generation proposed in western Arizona at various locations. A large amount of that generation is in the immediate vicinity of the Palo Verde Substation, which is on the far right side of my Attachment 4.

As a result of that large amount of generation that's being built there, the transmission owner at Palo Verde, which is the Salt River project -- has already constructed a second switchyard, which is in series with the North Gila, G-i-l-a -- ~~North Gila~~ Palo Verde project.

That second switchyard -- and I'll spell this for you also -- is called the Hasayampa Substation. And I

Imperial Valley --

Q Okay.

A -- and Otay.

Q On this map of -- that's -- or diagram of Attachment 4, are the facilities that connect at Otay Mesa or at the proposed Otay Mesa switchyard, are those all located in California?

A Yes, those are located in California, your Honor.

Q And the ones that are in -- interconnect with Imperial Valley or La Rosita are in Mexico?

A Well, I may have misunderstood your question. I thought you were asking: Is the proposed Otay Mesa switchyard site located in California?

Q No. The generators that are interconnecting with that location.

A The generators, yes. Now I understand your question. My apology.

The Otay Mesa project is located adjacent to the switchyard, the generating project that is proposed by Calpine, so that is in California.

~~AAP~~ AEP Resources has not disclosed to us the physical location of their proposed generation site. They have only applied to SDG&E for interconnection into the Otay Mesa switchyard, or if Otay Mesa is never built, they've applied for interconnection directly into the ~~Cal~~ Miguel switchyard.

That generation may be located in either U.S. or Mexico. They have not disclosed the location to us.

I only see two projects or two alternatives in the laundry list of the ~~ISO's~~ ORA's suggestions that would fall in that category; and, as I recall those without looking at the full attachment, they were a 500 kV system from the Edison system in the Serrano area to SONGS and then additions to the San Diego system South of SONGS. And they also talked about a 500 kV that went all the way to Miguel.

So that was one category of upgrades that might have the potential to be a full replacement project for Valley-Rainbow.

The other one they talked about was a high-voltage DC conversion. It's a little unclear to me how they would intend to build something like that. Clearly, that would require comparable right-of-way to a new 500 kV alternating current line, plus it would require massive substation constructions on new sites to accommodate the AC/DC terminal equipment.

And I don't know physically how that could be located, but in any case that may have the potential to be a displacement project. Again, that would need considerable reinforcement south of San Onofre as well as between Serrano and the SONGS area, which I believe is how they described it.

Q But, in essence, you would need -- in your opinion, the need for Valley-Rainbow would need to be -- or a project like it -- would need to be moved at least 10 years out on the planning horizon if not more before you'd consider the need to be eliminated at this point

Q Next, Mr. Korinek, Mr. Mihaly asked you yesterday a couple questions about South Bay and Encina, and in particular perhaps extending the existing RMR contracts.

Do you recall that line of questioning?

A I do.

Q And there was a question about what would happen if the plants were no longer economic to continue to run.

My question to you is if that were the case -- if it became uneconomic for South Bay and Encina to run, would that change the RMR cost that SDG&E would be -- would have to pay? ]

A Yes. I'm advised that ~~we~~ it changes~~d~~ the RMR costs significantly. I believe in my answer to the questions from Mr. Mihaly that I indicated that all of the units at South Bay except one were currently on RMR contracts. And I believe I stated that all five of the units at Encina are currently on RMR contracts.

On further review, I was in error. Only four of the units at Encina are on RMR contracts today; Encina 4 is not. And so currently South Bay 4 is not on an RMR contract, and neither is Encina 4.

In response to the cost of the RMR contracts, they are designed in a way that if the units are competitive in the market then, the only cost obligation that SDG&E's ratepayers have is for any additional operating costs that they may incur as a result of ISO operating orders.

However, if the units are no longer able to compete in the market, and therefore need full cost you change the input variables, are you saying would we get a different result?

Q If you modify -- all right, let's see.

What is the growth rate that is assumed from 2004 to 2005 in your table on page 3-1?

A I calculate the growth rate to be 3.79 percent between 2004 and 2005 with a one-in-ten-year case.

Q Now, if you were to assume a different growth rate, I'm assuming that you would have a different outcome for the peak load that is identified here in 2005; is that correct?

A If the underlying expected case, the 50/50 case and all things that drive that case were different, then the one-in-ten-year case would change accordingly.

Q Okay. Can you give me a better understanding of what are the variables that influence the projected growth rate?

A There's quite a long list. The process itself starts by modeling the sales to various customer classes, residential classes, driven by variables such as -- besides weather, income, housing types, energy prices.

In the small commercial industrial sectors, they're driven also by prices, weather and employment primarily. And after we've completed the energy portion, we use that to essentially drive the peak load along with some additional variables. There's an additional price variable for the peak load. And I guess there's a few other variables I should mention, too, like appliance ~~plants~~ and building you've identified, E2, E4, you assumed dry hydro conditions; is that correct?

A Yes.

Q Okay.

And when you say on this table that you assumed dry hydro conditions, does that mean you assumed dry hydro conditions in 2005, 2006, 2007, 2008, 2009 and 2010, all of those years?

A Yes.

Q Okay.

And when you assume dry hydro conditions, that means that you are assuming we will experience what's referred to as a one-in-35-year drought?

A That's what we modeled here is the drought that we had in the year 2000-2001, which has been characterized as a one-in-35-year drought.

Q Meaning, statistically speaking, you would expect it to occur one year out of 35?

A Yeah, or alternatively it's the second worst in the seventy ~~seven~~ years of history is what that really means.

Q Okay.

So the benefit number shown here on your Table 1-1 of 504 million and some change, that's calculated assuming six years in a row of drought at a level of one -- at a level expected once every 35 years?

A Yes.

Q And in your rebuttal testimony, Exhibit 5, Chapter 5, page 25, lines 15 to 16 you state, and I quote:

so I could plot it here.

I overlaid this on a similar plot that we had for our typical week, and it's very close; so we would not have any differences because of hourly loads.

But I just plotted that there -- I don't know if they ran four weeks -- different weeks or for typical weeks, but they should be the same in any -- they're still very similar in any event.

Q Are you --

ALJ COOKE: By "they," you mean who?

THE WITNESS: I don't know if ORA ran four different weeks or four identical weeks.

ALJ COOKE: Thank you.

MR. SCARFF: Q Are you aware that the SERASYM submodel called LOADSYM -- that's all caps L-O-A-D-S-Y-M -- does not use typical weeks as the building blocks for which months are made?

A No, I'm not aware.

Q But the --

A I don't know if it does or it does not.

I just don't know.

Q Do you know which week in January this figure represents from the ORA data?

A I could check it, and it might be worthwhile just looking -- if there are four weeks -- and then to see just how much difference there is.

But I don't know.

Q Certainly. Could you do that?